Decision **ALTERNATE PROPOSED DECISION OF COMMISSIONER LYNCH (Mailed 11/15/2002)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Authority to Institute a Rate Stabilization Plan with a Rate Increase and End of Rate Freeze Tariffs.	Application 00-11-038 (Filed November 16, 2000)
Emergency Application of Pacific Gas and Electric Company to Adopt a Rate Stabilization Plan. (U 39 E)	Application 00-11-056 (Filed November 22, 2000)
Petition of THE UTILITY REFORM NETWORK for Modification of Resolution E-3527.	Application 00-10-028 (Filed October 17, 2000

TABLE OF CONTENTS

ORDER ADOPTING INTERIM ALLOCATION OF THE 2003 REVENUE REQUIREMENT OF THE CALIFORNIA DEPARTMENT OF WATER RESOURCES

Summary

This decision allocates among the three major California utilities the cost of the California Department of Water Resources' (DWR) forecast 2003 revenue requirement for its power purchase program.[1]

The parties presented four different allocation methodologies. The allocation methodology proposed by the Commission's Office of Ratepayer Advocates (ORA) is the fairest, and we adopt it with modifications. In essence, the methodology we adopt pools the total costs of DWR's contracts and allocates those costs among the utilities on the basis of the quantity of energy supplied to each utility from the contracts. The resulting costs for each utility are remitted to DWR.

We also resolve a number of issues relating to how the allocation of the revenue requirement is calculated, including issues relating to the proper treatment of revenues from sales of excess energy, procurement of ancillary services, inclusion of funds for demand reduction efforts, and the use of particular modeling runs. Issues relating to the true-up of DWR's 2001-2002 revenue requirement will be addressed after actual data for 2002 becomes available, and are not resolved here.

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[1] The three major utilities are Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). For more background on DWR's power purchase program and revenue requirement, and on the relevant statutes, please see Decision (D.) 02-02-052, pp. 6-12.

Due to the mandatory expedited schedule for this proceeding, its complex interaction with other Commission proceedings, concerns about due process, and the constantly evolving nature of the California electricity market, the evidentiary record does not support a final allocation of DWR's revenue requirement for all of 2003. Accordingly, the allocation we adopt today is interim, and will be superseded by a later allocation. We believe that a final allocation for 2003 can be achieved expeditiously, but it will require additional input from DWR.

As described below in more detail, in order for us to optimize our allocation for 2003, we need DWR to update it's modeling efforts to incorporate direct access migration, to provide all parties an equal opportunity to contribute to the modeling assumptions and inputs, to treat sales of excess energy consistently with the protocols adopted in D.02-09-053, and to refine assumptions regarding ancillary services and cash reserve levels. We cannot require DWR to submit a supplemental revenue requirement determination for 2003, but we need a supplemental determination if our allocation is to be as fair and comprehensive as possible. Without such cooperation and timely resubmittal from DWR, we may be required to set the costs charged to ratepayers at a rate that is more than a billion dollars more than is necessary. Such an unnecessary burden on ratepayers must be avoided to prevent significant harm to individuals, businesses and the economy of California.

While it is up to DWR to manage its own process for developing such a supplemental determination, we have set out a process for how the Commission will implement this supplemental determination, and we strongly encourage DWR to promptly submit a supplemental determination with the additional information we identify. This approach will result in a more accurate and equitable allocation of DWR's 2003 revenue requirement, and a likely reduction in the total amount of DWR's 2003 revenue requirement, with a corresponding decrease in the rates needed to be paid by consumers.

The Commission acknowledges the hard work and cooperation of the participants and Commission staff in meeting this proceeding's tight deadlines.

Chronology of the Proceeding

- August 16, 2002 – DWR issued its Determination of Revenue Requirements For the Period January 1, 2003 Through December 31, 2003 With Reexamination and Redetermination For the Period January 17, 2001 Through December 31, 2002 (Determination).
- August 19, 2002 - DWR submitted its Determination to the Commission.[2]
- August 29, 2002 - Pre-Hearing Conference Statements were filed and served by the Commission's Office of Ratepayer Advocates (ORA), the Energy Producers and Users Coalition (EPUC),[3] and Modesto Irrigation District.
- September 4, 2002 – A Pre-Hearing Conference was held at the Commission.
- September 12, 2002 – A technical workshop was conducted by the staff of the Commission's Energy Division.
- September 13, 2002 – Notices of recommended allocation method were filed and served by PG&E, SDG&E, SCE, and ORA.

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[2] Under the terms of the Rate Agreement, this delivery triggers the 120-day clock for Commission action.

[3] Along with EPUC, the statement was also on behalf of Kimberly Clark Corporation and Goodrich Aerostructures Group.

- September 23, 2002 – Opening testimony was served by PG&E, SDG&E, SCE, and ORA.
- September 30, 2002 – Rebuttal testimony was served by PG&E, SDG&E, SCE, ORA, and The Utility Reform Network (TURN).
- October 2, 2002 - Supplemental testimony was served by PG&E and DWR.
- October 2-4, 2002 – Evidentiary hearings were held at the Commission.
- October 16, 2002 – Opening briefs were filed by PG&E, SDG&E, SCE, and ORA.
- October 23, 2002 – Reply briefs were filed by PG&E, SDG&E, SCE, ORA, and TURN.

The Issues

The issues addressed here are: 1) allocation of DWR's 2003 revenue requirement among the three utilities; 2) treatment of excess energy sales and revenues; 3) treatment of ancillary services; 4) modeling questions; 5) exclusion of costs for demand reduction efforts; and 6) ratemaking and remittance procedures. Pursuant to the oral ruling of Administrative Law Judge (ALJ) Allen, issues relating to the true-up of DWR's 2001-2002 revenue requirement have been deferred until actual data for 2002 is available.

Allocation of DWR's 2003 Revenue Requirement

The main issue in this proceeding is how to allocate DWR's 2003 revenue requirement among the three major utilities. This is not a brand-new task; we have previously allocated DWR's revenue requirement, but not in the same context that we face today. Nevertheless, two of our recent decisions, D.02-02-052 and D.02-09-053, provide some guidance on this issue.

In D.02-02-052, we allocated DWR's revenue requirement for 2001 and 2002.[4] In that decision, we evaluated a number of competing proposals, and ultimately adopted an allocation method proposed by SCE. We summarized that method and its basis as follows:

> SCE characterizes the procurement costs of DWR fixed long term (90 days or longer) contracts as costs incurred to meet the joint net short position of all three utilities. Because these long-term contracts provided a benefit to the entire State of California by lowering electricity prices on the spot market, SCE proposes that such fixed contract costs be allocated pro rata based on each utility's net short position.
>
> For short-term purchases (less than 90 days), however, SCE proposes that supply costs be allocated between PG&E and southern California utility customers based on the separate zonal cost of supplies using Path 15 as a dividing point.
> (*Id.*, p.48.)

For 2003, however, DWR will not be making any short-term purchases. (*See*, Water Code section 80260.) Accordingly, we do not need to allocate the costs of short-term purchases for 2003, but we do need to again allocate the costs of the existing long-term contracts.

Subsequently, in D.02-09-053, we adopted a policy of allocating the variable costs of the existing DWR contracts to the three major utilities. As of January 1, 2003, the utilities will be placing those contracts into their resource portfolios to be scheduled and dispatched in a least-cost manner. This was done as part of the process of requiring the utilities to resume their procurement planning role. As we stated, "…the utilities will now perform all of the

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[4] Readers seeking detailed background to the present decision should refer to D.02-02-052. D.02-02-052 was modified by D.02-03-062 and clarified by D.02-09-045. For brevity, this decision will simply cite to D.02-02-052.

day-to-day scheduling, dispatch and administrative functions for the DWR contracts allocated to their portfolios, just as they will perform those functions for their existing resources and new procurements. Legal title, financial reporting and responsibility for the payment of contract-related bills will remain with DWR." (D.02-09-053, p.5.)

While D.02-09-053 established the policy that the variable costs of each contract should follow contract allocation (*id.*, p.6), it left to this proceeding the determination of the proper allocation of the total DWR revenue requirement. As a practical matter, since we are not changing the allocation of variable costs from D.02-09-053, what remains to be allocated here are costs other than variable costs, which consist primarily of the fixed costs of the contracts and DWR's related administrative and general costs.

The contents of DWR's 2003 revenue requirement are shown in the following summary tables:

DWR's August 16th Determination of 2003 Power Charge Expenses

Power Costs	$4,119,902,243
Administrative and General Expenses	$28,400,000
Ancillary services	$170,454,426
Increase in Operating Fund Balance	$517,399,690
Total DWR Power Charge Expense	**$4,836,156,359**
Less: Revenue from Sales of Excess Power	($128,885,940)
Less: Interest Earnings on Fund Balances	($59,007,505)
Total Ratepayer Revenue Requirement	**$4,648,262,914**

Source: DWR August 16th Determination, Table A-1

The positions of a number of parties shifted during the course of this proceeding, as their understanding of other parties' positions (and their own positions) evolved. These migrations of position were likely exaggerated by the highly expedited schedule, as parties had a relatively short time to do discovery and analysis prior to testimony and hearings. While this movement has resulted in some increased alignment of positions, the four most active parties still presented four different allocation methodologies.

SCE

SCE has proposed that the allocation of fixed costs follow the methodology adopted in D.02-09-053 for allocation of variable costs. This approach, commonly referred to as "costs-follow-contracts," would result in the fixed costs of DWR contracts being allocated to the same utilities to which the variable costs of those contracts were allocated in D.02-09-053.

According to SCE, the advantage of this approach is its internal consistency, as it avoids the possibility of one utility receiving a large allocation of variable costs under one method and a large allocation of fixed costs under another method. In addition to avoiding a mix of different allocation methods, which SCE regards as potentially unfair, SCE argues that its proposal is unique in that it provides the only approach that does not require future proceedings to establish future year allocations. SCE argues in the alternative that if the Commission were to decide not to use the "costs-follow-contracts" approach, then the Commission should adopt ORA's recommended approach.

SCE's "costs-follow-contracts" proposal attempts to use the allocation of contracts adopted in D.02-09-053 to allocate fixed contract costs, but SCE has not established that doing so is appropriate. D.02-02-052 addressed fixed costs, and accordingly is the more directly applicable precedent than D.02-09-053, which focused on variable costs. SCE's proposal conflicts with D.02-02-052.[5] While we are not necessarily bound to follow D.02-02-052, SCE has not persuaded us that there is a good reason for departing from that decision.

In D.02-02-052 we stated:

> [W]e agree with the goal of allocating DWR costs in relation to the costs of providing service. We do not believe, however, that segregating disproportionately higher priced DWR power for allocation exclusively to northern California consumers is a proper or fair application of traditional cost-based ratemaking policies. (*Id.*, p.4.)
>
> One measure of cost causation in relation to the three separate utility service territories would be evidence that DWR had actually procured separate portfolios of supplies specifically targeted toward each respective utility's customers. If DWR had expressly procured a separate portfolio of supplies for each utility service territory, there would be a strong cause-and-effect relationship between location of supplies and specific utility service territory served. This, in fact, did not occur. (*Id.*, pp.59-60.)

We concluded that:

> DWR thus has not maintained separate portfolios to meet the net short positions of each utility. Any allocation of power purchased under the DWR contracts and spot market purchases for each respective service area by assuming distinctly separate sources of supply for each utility is not consistent with the way DWR constructed its portfolio of supplies, and would not necessarily result in

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[5] In addition, SCE's argument is not actually supported by D.02-09-053. That decision expressly rejected the same argument that Edison makes here, and left the issue open, to be decided in this proceeding. (*Id.*, p.38.)

> any more logical or accurate cost causation than a statewide pro rata approach. (*Id*., p.60.)

Our allocation in D.02-02-052 recognized the primarily integrated nature of power procurement undertaken by DWR for California utility customers, but we also adjusted for utility-specific differences, where applicable. Utility-specific adjustments were determined to be appropriate only in the case of short-term purchases, which we allocated geographically. Short-term purchases are not present here, eliminating the need for corresponding utility-specific adjustments to the allocation methodology.

Since DWR signed contracts for a statewide need, allocating the fixed costs of contracts to utilities based upon geographic location does not match how or why those contracts were obtained. It would be arbitrary and unfair for one or more utilities to end up with a disproportionate number of high-priced contracts when DWR was not trying to balance costs among utilities.

TURN notes that SCE's approach has the "appeal of simplicity and finality." Nevertheless, TURN argues that while SCE's "costs-follow-contracts" approach may have potential as a long term or future methodology, it is too soon to adopt it, particularly while the contracts themselves are in the process of being renegotiated. (TURN Reply Brief, p. 5.)[6] As TURN points out, with the contracts in active renegotiation, we cannot know how the cost of each contract may change in the future, and we have no way to evaluate the ultimate fairness of this allocation approach. PG&E similarly believes that "costs-follow-contracts" may

[6] The state is attempting to renegotiate the existing DWR contracts in order to reduce their cost. DWR's revenue requirement would be reduced to the extent the state is successful in this effort.

be appropriate after contract renegotiations are concluded, but not before. (Ex. 1, p.1-8.)

PG&E

PG&E proposes that DWR's revenue requirement be allocated to each utility in proportion to each utility's 2003 net short, adjusted to add back load loss from direct access and departing load customers, resulting in what PG&E calls "pre-load migration net short." From that initial allocation, PG&E would then subtract the variable costs that have been allocated to each utility. The remainder for each utility is the fixed cost component that gets remitted to DWR. According to PG&E, this method best takes into account direct access and departing load, and also best reflects the cost drivers of DWR's original contracting activities.

Compared with SCE's proposal, PG&E's is more consistent with DWR's original procurement focus, which was the aggregate net short position of the three utilities. Nevertheless, the passage of time, and the corresponding changes in the electricity market, render PG&E's proposal less appropriate than it may have been a year ago. When the Commission was examining the allocation of DWR's revenue requirement for 2001 and 2002, DWR was buying power for each utility's net short via a mix of short-term and longer-term contract purchases. For 2003, DWR is out of the procurement business, and the energy delivered to each utility by long-term DWR contracts does not necessarily match that utility's net short.

These changes render PG&E's allocation unfair. As ORA points out:

> [A]llocation on the basis of net short can lead to double counting and the imposition of inequitable costs for its residual net short. For example, a utility allocated a share of contract energy that is smaller than its share of net short will end up paying for its residual net short twice, once as

> part of the DWR revenue requirement, and a second time in the open market as the utility resumes responsibility for procurement of its residual net short. (ORA Reply Brief, p.3, citing to SCE's Opening Brief.)

TURN also makes the same point – PG&E's proposal could result in customers essentially paying twice for the same energy.

SDG&E

SDG&E proposes a "postage stamp" allocation, with DWR contract costs allocated to each utility in proportion to the quantity of energy supplied by DWR to each utility. However, SDG&E does not subtract out the variable costs the way that PG&E does[7]. Instead, SDG&E allocates the fixed costs independently of the variable costs. According to SDG&E, variable costs have already been allocated in D.02-09-053, have no role in the allocation of fixed costs, and need not be considered here. SDG&E argues that its proposed allocation is the most consistent with D.02-02-052.

The initial part of SDG&E's approach, with its allocation by supplied energy, is relatively equitable. By pooling all of the costs, it reflects the fact that DWR purchases and contracts were intended to cover the *aggregate* net short position of the three utilities. SDG&E's approach is more consistent with DWR's actual practices than is SCE's approach, which disaggregates the costs to the three utilities. SDG&E keeps the costs and benefits more closely aligned than SCE or PG&E, because SDG&E starts with the costs aggregated (the way that DWR incurred them), and then allocates them on the basis of what the contracts will actually provide in 2003: energy. DWR is not providing for the utilities' net

[7] ORA, like PG&E, subtracts variable costs to come up with a residual amount of fixed costs.

short. Supplied energy, as proposed by SDG&E, is the most appropriate criteria for allocating the fixed costs of the DWR contracts.

However, SDG&E's subsequent disregard of variable costs gives an unfair result, and is criticized by all other parties. ORA makes the basic point:

> SDG&E's direct allocation of fixed costs can unfairly burden a utility with a disproportionate share of variable costs. SDG&E's method leaves utilities sharing fixed costs, but not sharing variable costs. A utility with a disproportionally large share of variable costs ends up paying all of their own variable costs as well as a greater than proportionate share of others' fixed costs. (ORA Opening Brief, p.8.)

PG&E provides a hypothetical example to illustrate the problem:

> Under the example there are two utilities, and two contracts. The two contracts are expected to have the same overall costs. One contract has all fixed costs, and is allocated to one of the utilities. The other contract has all variable costs, and is allocated to the other utility…[T]he only distinction between the circumstances the two utilities face is that one has been allocated a contract that is all variable costs, while the other has been allocated a contract that is all fixed costs…The example illustrates that under SDG&E's approach the utility to which the variable cost contract has been allocated would bear all of the variable costs, plus half of the fixed costs, resulting in an overall burden for it of three-quarters of the costs. The other utility would bear only half of the fixed costs, resulting in an overall burden for it of one-quarter of the costs. (PG&E Opening Brief, pp. 13-14.)

SCE and TURN agree with ORA and PG&E that SDG&E's proposal to ignore variable costs is unfair.

ORA

ORA's proposal for allocation is also a "postage stamp" allocation. ORA's proposal starts out somewhat similarly to SDG&E, with a pro-rata allocation of the DWR revenue requirement based on each utility's share of the total amount of DWR delivered energy. ORA then departs from SDG&E by subtracting out the variable costs that have been allocated to each utility, resulting in a residual (fixed cost) revenue requirement.

According to ORA, the advantages of this method are that all utility bundled customers would be charged the same rate, and the allocation derived is the fairest, because it most accurately associates energy costs with the energy that the utility is actually getting from DWR's contracts. (ORA Opening Brief, pp.3-4.)

While it is not clear that all bundled customers would actually be charged the same "rate" for DWR energy, ORA's proposal does treat all bundled customers equitably. ORA's overall approach is in fact the fairest of those proposed. Like SDG&E's proposal, ORA's proposal allocates costs in a way that corresponds to the benefits received (energy), and spreads the pain of those DWR contracts that are particularly expensive. ORA's proposal to distribute the costs of DWR contracts statewide among all ratepayers is more equitable and less arbitrary than the proposals of SCE and PG&E. Furthermore, by subtracting out the variable costs that we allocated in D.02-09-053, ORA's proposal avoids the problems caused by SDG&E's proposal to allocate fixed costs independently from variable costs.

An integral part of ORA's proposal is its recommendation that the Commission apply what ORA calls a "pre-Direct Access metric." ORA argues that the Commission should adjust the allocation of DWR's revenue requirement to take into consideration direct access and departing load customers subject to the Cost Responsibility Surcharge (CRS) set in R.02-01-011. In its Reply Brief, ORA acknowledges that this adjustment requires the results of a

"Direct Access-In" modeling run from DWR's consultant, which had not yet been performed. ORA anticipated that such a modeling run would be completed well prior to the issuance of a Proposed Decision in this proceeding, and accordingly could be incorporated here. (ORA Reply Brief, p. 4, fn. 2.) Unfortunately, that did not happen, and the modeling run could not be completed in time to be utilized in this proceeding.

ORA's proposed adjustment received broad support. In addition to TURN, even parties who proposed different allocation methodologies did not quarrel with ORA's proposed adjustment. PG&E generally agrees with ORA that the allocation of DWR's revenue requirement should take into account direct access migration, and that the allocation should be consistent with the treatment of direct access and departing load in the CRS proceeding. (PG&E Reply Brief, p.4.) While SCE indicates some reservations (due to its questioning of certain direct access and departing load data), it endorses ORA's allocation proposal - including direct access and departing load adjustments - as the next-best alternative to its own proposal. (SCE Opening Brief, p.9.)

The direct access adjustment proposed by ORA is appropriate. ORA's proposed departing load adjustment may also be appropriate, but it is not clear when the information necessary to perform that adjustment will be available, as resolution of that issue has been deferred in the CRS proceeding.

Nevertheless, despite its merits, we are unable to incorporate the direct access adjustment at this time, as the evidentiary record in this proceeding does not provide adequate support for that adjustment. Accordingly, for the time being we are adopting ORA's proposal without the direct access adjustments. As soon as we are able to incorporate the appropriate modeling runs, we will make the necessary adjustments to reflect direct access. DWR should incorporate a

"Direct-Access-In" modeling run into any supplemental determination it submits, so that we can make the adjustments described above.

We do need to make several minor modifications to ORA's methodology. TURN, which supports ORA's approach,[8] suggests two minor modifications. First, TURN argues that:

> [T]he revenues associated with off-system sales of DWR power should **not** be "pooled" and then allocated among the three utilities. Rather, these revenues should *directly offset* the revenue requirement of the dispatching utility. Otherwise, the incentive for economic dispatch would be seriously distorted. (TURN Reply Brief, p.3, emphasis in original.)

The three utilities concur on this point, and we also agree.[9] Pooling would reduce the incentive for a utility to maximize the revenues from its sales of surplus energy. As discussed further below, revenues from sales of surplus energy should be credited to the portion of the revenue requirement allocated to the customers of the utility making the sale.

TURN also recommends that instead of using the numbers for "DWR Delivered Energy" (sometimes referred to as retail energy), as proposed by ORA, it would be more appropriate to use the numbers for "DWR Supplied Energy" (sometimes referred to as wholesale energy). The basic difference between these two is that Delivered Energy has line losses subtracted out, while Supplied Energy reflects total DWR supplies prior to the subtraction of line losses.

[8] In testimony, TURN supported PG&E's proposal. In its Reply Brief, TURN changed its position to support ORA's proposal, but only if it incorporates the direct access adjustment described above.

[9] It does not appear that ORA is advocating pooling of revenues, but ORA's calculations reflect a pooled approach.

TURN's recommendation (which is similar to SDG&E's position on this point) results in the allocation of the revenue requirements better reflecting the differing line losses of the utilities, because DWR does not need to send as much energy to those utilities with lower line losses. To allocate DWR's revenue requirement on the basis of the amount of energy *received* by each utility would result in customers of utilities with low line losses paying for the energy lost by the systems of utilities with larger line losses. Accordingly, we will modify ORA's proposal as recommended by TURN, and use the amount of energy *sent* to each utility, rather than the amount of energy received, as the basis for allocating DWR's revenue requirement.

In addition to TURN's recommendations, PG&E points out that ORA includes tolling charges associated with DWR must-take contracts as a variable cost. (PG&E Reply Brief, p.7.) From a dispatch perspective, these charges are a sunk or unavoidable cost. In D.02-09-053, we limited variable costs to those that could be avoided by dispatch decision. While tolling contracts do have a variable component, the variable component is not avoidable by dispatch decision. DWR and the other utilities concur with PG&E that tolling contracts should be considered a fixed cost. To apply ORA's allocation method in a manner that is consistent with D.02-09-053, we will treat charges associated with tolling contracts as fixed costs, not variable costs.

Our adopted interim methodology for the allocation of costs gives the results shown on the following table, which also shows how those results compare with the results of the other proposed methodologies:

Table A: Proposed and Interim Adopted Allocations

Allocation	**PG&E**		**SCE**		**SDG&E**		**Total**
PG&E	$2,176,022,065	49%	$1,459,329,931	33%	$842,456,493	19%	$4,477,808,488

SCE	$2,198,999,901	48%	$1,705,579,862	37%	$665,300,022	15%	$4,569,879,786
SDG&E	$1,994,972,168	44%	$1,890,309,902	41%	$689,636,035	15%	$4,574,918,104
ORA*	$2,001,283,866	44%	$1,892,174,406	41%	$676,419,060	15%	$4,569,877,333
ORA**	$1,850,485,458	44%	$1,768,149,536	42%	$605,630,887	14%	$4,224,265,882

* As filed
**As modified and adopted.
Note: Total amounts allocated are different because of individual proposed adjustments.

The following tables provides more detailed information on the adopted allocation:

TABLE B: Summary of Interim Adopted Allocation

	PG&E	SCE	SDG&E	Total
	$	$	$	
Ancillary Services	$74,413,275	$71,766,569	$24,274,582	$170,454,426
Variable Contract Costs	$85,661,819	$65,501,750	$68,722,250	$219,885,819
Fixed Contract Costs	$1,712,915,242	$1,669,104,118	$517,997,064	$3,900,016,423
Administrative and General Expenses	$12,398,253	$11,957,276	$4,044,472	$28,400,000
Operating Reserves	$0	$0	$0	$0
Less:				
DWR Surplus Sales Revenue	$(9,142,922)	$(25,336,197)	$(1,004,163)	$(35,483,282)
Interest Earnings	$(25,760,209)	$(24,843,979)	$(8,403,317)	$(59,007,505)
DWR Revenue from Ratepayers	$1,850,485,458	$1,768,149,536	$605,630,887	$4,224,265,882

In order to have consistent assumptions and inputs, neither table adjusts for direct access (*i.e.*, they do not incorporate a "Direct Access-In" modeling run), and both tables reflect the use of the modeling run known as

PROSYM 36.[10] For additional detail on our adopted methodology, please refer to Appendix A.

Excess Energy Sales and Revenues

Treatment of revenues from sales of excess energy is an area that remains very much in flux, despite our best efforts to pin it down. To the extent details are available, they are set forth in Appendix A. Otherwise, we are primarily adopting general principles to provide guidance as this issue is subject to further refinement by the Commission, utilities, and DWR.

In D.02-09-053, we addressed the treatment of revenues attributable to excess energy sales:

> Sales revenues should be accounted for based on the composite of resources that each utility dispatches from its portfolio, rather than the timing with which specific resources were acquired. Accordingly, we will prorate sales revenues between the utility's revenue requirements and DWR's revenue requirements based on the relative quantities dispatched from utility generating assets (including contracts and market purchases in the future) and the DWR contracts. (*Id.*, pp.42-43.)

We further specified, in some detail:

> Given these circumstances, we believe that the pro rata approach is the most equitable way to determine the relative amounts of retail and surplus sales revenues between DWR and the utilities. However, based on DWR's comments, we clarify that this approach involves the following steps: [fn. omitted] (1) calculating the amount of surplus sales based on

[10] For Table A (and for our own analysis), it was necessary to use one consistent model run to properly compare the proposals. The parties did not all use the same modeling run, with some using PROSYM 36, while others used PROSYM 37. For the reasons described below in the section titled "Modeling Issues," we chose to use PROSYM 36.

> the excess of total utility portfolio resources (including DWR contracts allocated today) relative to loads, (2) allocating those sales revenues between DWR and the utilities based on the relative quantities dispatched from utility resources and the DWR contracts, and (3) calculating the revenue from retail customers using the difference between dispatched quantities and the surplus sales quantities calculated under (2). We direct the utilities to work with DWR to develop specific accounting and reporting procedures consistent with the pro rata approach we adopt today. These procedures should be developed in DWR's 2003 revenue requirements proceeding. (*Id.*, pp. 44-45.)

Today we continue to flesh out the approach adopted in D.02-09-053. The utilities were granted an extension of time to submit their procedures for implementing that decision, and filed them on October 8, 2002, after the close of evidentiary hearings in this proceeding. Even with the extension, the utilities' proposed procedures are still very much works-in-progress, and do not reflect final agreement between the utilities and DWR. This reinforces the constantly moving target nature of this proceeding, but our task is made somewhat easier by the fact that SDG&E, SCE, ORA, and TURN largely agree on the general principles to be applied.[11]

As we discussed above, revenues associated with off-system sales of DWR power should not be pooled, but instead should offset the portion of the DWR revenue requirement allocated to the customers of the dispatching utility. This approach is consistent with the policy of D.02-09-053, as it maximizes the incentives for utilities to make sales of surplus energy.

As SDG&E puts it:

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[11] PG&E's position on this issue is not entirely clear.

> SDG&E recommends that revenues from sales of excess DWR energy be apportioned to the customers of the utility making the sales, and not to all utilities' customers as a pool. D.02-09-053 declined to address this issue, instead deferring it to this proceeding. SDG&E further proposes that revenues from sales of surplus DWR energy will be credited to the DWR revenue requirement allocated to the utility's customers. By apportioning the revenues in this manner, the utility making the sale will know that its action will directly benefit its customers. If revenues from those sales were pooled, there would be little incentive for any one utility in making those sales because the results would be spread among the customers of all utilities. Keeping sales revenue with the utility making the sale is also consistent with D.02-09-053's requirement that variable costs follow contracts. The revenue from these surplus sales can vary depending, at least to an extent, on the decisions of the utility. Market conditions will be the primary factor affecting the revenue from these sales. The Commission should therefore adopt SDG&E's proposal and order that the revenue from these sales be apportioned to the customers of the utility making the sales. (SDG&E Opening Brief, pp.5-6.)

SCE and SDG&E each propose certain adjustments to this general principle, with each claiming their proposal will render the outcome more closely congruent with the complexities of reality. SCE proposes to exclude what it calls "resource specific sales," such as off-system sales from resources located outside the ISO control area. SDG&E, instead of applying the ratio of total URG to DWR energy, uses only must-take energy in its calculation.[12] These proposed

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[12] While SDG&E maintains that its use of must-take energy best emulates the typical surplus sale hour scenario, SDG&E indicates (in response to TURN's Rebuttal Testimony) that it is willing to eliminate this aspect of its proposal, and notes that the outcome of the two calculation approaches is nearly identical. (SDG&E Opening Brief, p.6.)

adjustments add needless complexity and opportunities for gaming, and are inconsistent with our clear statement in D.02-09-053 that surplus sales calculations are to be based on *total* utility portfolio resources. (*Id.*, p.7.)

Our task is complicated by the fact that DWR's August 16 Determination was prepared prior to the issuance of D.02-09-053, and accordingly does not reflect our adopted treatment of revenues from sales of surplus energy. While DWR subtracts anticipated surplus sales revenues from its revenue requirement, DWR's surplus sales revenues are likely to be significantly different than those assumed in the August 16 Determination.

The sales protocol adopted in D.02-09-053 will cause DWR off-system sales to decrease, with a corresponding increase in utility off-system sales. Likewise, DWR retail sales will increase, with a corresponding decrease in utility retail sales. In essence, the revenues collected by DWR would be based on a power charge calculated using retail sales numbers from its August 16 Determination (rather than from the protocol set forth in D.02-09-053), but applied to a much larger retail sales volume. This will result in utility undercollection and DWR overcollection relative to the figures in DWR's August 16 Determination.

SCE, SDG&E, TURN, and ORA agree that the revised allocation protocols for sales adopted in D.02-09-053 will require an adjustment to DWR figures to reflect greater retail sales and less off-system sales revenues by DWR. DWR should incorporate an appropriate adjustment in its supplemental determination.

SCE proposes establishing utility-specific balancing accounts that would capture each utility's allocation of DWR costs and each utility's energy sales revenues paid to DWR. This tracking of the costs and revenues related to the DWR contracts allocated to each utility would be for the purpose of future allocation true-ups. (SCE Opening Brief, pp.10-11.) The proper scope and nature of allocation true-ups has not been determined. As described below, all issues relating to the true-up of DWR's 2001-2002 revenue requirement have been deferred until 2003. It would be premature to approve balancing accounts for 2003 before determining the propriety of recovery for 2001 and 2002. SCE's proposal to establish utility-specific balancing accounts is not approved here, but SCE may raise the issue again in the portion of this proceeding addressing the true-up of DWR's revenue requirement for 2001-2002.

The utilities are in the process of negotiating servicing agreements with DWR, and those negotiations provide a reasonable forum for the resolution of the administrative details needed to implement the general policies we adopt on this issue. DWR should incorporate in its supplemental determination the updated terms of the servicing agreements, along with the protocols adopted in D.02-09-053.

Ancillary Services

DWR asserts that it continues to have authority to obtain and pay for ancillary services, and estimates its 2003 cost for doing so at approximately $170 million. In its August 16 Determination, DWR notes that: "If the Department is not required to pay for ancillary services costs in 2003, the total revenue requirement would decrease by $170 million." (Determination, p.31.) There is some consensus, some dispute, and possibly some confusion amongst the parties on this issue.

SDG&E proposes in its testimony that the $170 million be removed from DWR's revenue requirement. According to SDG&E, each utility should be responsible for the cost of providing ancillary services for its bundled load. In addition to administrative simplicity, SDG&E argues that each IOU should decide for itself how to provide ancillary services, and notes that DWR has not entered into contracts for ancillary services, but rather has relied upon the ISO to provide them.

Conceptually, PG&E agrees with SDG&E that the utilities should be responsible for their respective ancillary service obligations. However, PG&E believes it is premature to remove ancillary services costs from DWR's 2003 revenue requirement before PG&E and SCE are restored to creditworthiness. PG&E would not object to SDG&E's proposal if it were to be applied only to SDG&E, but does object to applying SDG&E's proposal to PG&E. Accordingly, PG&E would leave the $170 million (or at least some portion of that amount) in DWR's revenue requirement to provide creditworthy backing to the utilities, but each utility would be responsible for the costs DWR incurs on behalf of its customers.[13] PG&E recommends that DWR's revenue requirement for ancillary services be allocated separately, and not subject to the allocation methodology otherwise adopted here.

In its Opening Brief, SCE states that it agrees with SDG&E, but its description of what it proposes sounds more like PG&E's position. In its Reply Brief, SCE essentially states that this issue should be left to the individual utilities to address with DWR or the ISO.

TURN agrees with SDG&E and PG&E that ancillary services costs should be allocated to the utility for which those ancillary services are purchased. TURN is neutral between the two proposals, and sees no direct impact to ratepayers from choosing one over the other, as either proposal would result in

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[13] SDG&E argues that PG&E could utilize other forms of credit backing instead of DWR's revenue requirement.

payment coming from the utility that uses the services. ORA does not appear to distinguish between the PG&E and SDG&E proposals.

There appears to be consensus among the parties on one aspect of this issue: each utility should be responsible for the cost of ancillary services provided to its customers, regardless of whether those ancillary services are provided by the utility or by DWR. In theory, we agree with all parties that a general allocation methodology should not be applied to the cost of ancillary services, but rather each utility should pay for ancillary services provided to its customers; if DWR provides those services, then the utility customers receiving those services should pay DWR.

Unfortunately, this is an area where the gap between theory and practice is larger in practice than it is in theory. In response to the parties, DWR asserts that the estimated costs of ancillary services should remain in its 2003 revenue requirement, and that it is reasonable to continue to include them in the revenue requirement. (DWR Memorandum, dated October 23, 2002.) DWR's insistence at keeping the $170 million in forecast ancillary services costs in its revenue requirement, coupled with the terms of the Rate Agreement, leave us no choice but to leave those dollars in place, to be passed on to the ratepayers. Even though we agree with SDG&E that there is no need for the $170 million to remain in the DWR revenue requirement, we cannot remove them.

We urge DWR to reconsider its demand for $170 million in ratepayer money for ancillary services. DWR's supplemental determination should look closely at the assumptions used in its forecast of costs for ancillary services. All utilities should provide DWR with current data, assumptions, and forecasts relating to DWR's potential ancillary services costs, so DWR can consider that information in preparing its supplemental determination.

There are significant real-world differences between the utilities on this issue (including creditworthiness, self-provision of ancillary services, invoicing, and other administrative issues). This renders a generalized allocation approach less appropriate, but DWR's simplistic approach to ancillary services leaves that as our only choice.

DWR's estimate of ancillary services costs did not distinguish between the utilities. DWR estimated a cost of ancillary services based upon volumes of delivered energy, and DWR's total estimated cost for ancillary services did not take into consideration differences such as the relative creditworthiness of SDG&E and PG&E.

Were our allocation to take into consideration differences between the utilities, such as the actual amount of ancillary services provided by DWR, it would result in a reduction of the costs of ancillary services for some utilities, such as SDG&E. But DWR's refusal to reduce the total dollar amount of its revenue requirement for ancillary services would render the resulting allocation inequitable. Under DWR's approach, the pie remains the same size even if a large slice of it is removed.

This means that we cannot allocate the costs of ancillary services in the manner recommended by the parties, which we prefer. Instead, we can only apply a more generalized allocation methodology. Accordingly, we will allocate DWR's $170 million for ancillary services using the same approach we have adopted for allocating DWR's fixed costs. We will revisit this allocation approach during our evaluation of DWR's supplemental determination, in the hopes of implementing an allocation that results in each utility being responsible for the cost of providing ancillary services for its bundled load.

Modeling Issues

DWR's August 16 Determination was based upon a modeling run referred to as PROSYM 36. Subsequently, DWR performed another modeling run, PROSYM 37. The results of PROSYM 37 were presented in DWR's Exhibit 12, which was distributed on October 2, and Exhibit 12-A, which was distributed on October 4. PROSYM 37 incorporates corrections suggested by PG&E, as well as post-processing adjustments that factor in some impacts of D.02-09-053. DWR did not modify the revenue requirement in its August 16 Determination as a result of PROSYM 37, but rather provided the new run for the Commission's use in allocating the revenue requirement among the utilities.

PG&E and ORA support the use of PROSYM 37, on the grounds that it contains the most current and accurate information.

SDG&E and SCE argue that PROSYM 37 should not be used here. While not specifically identifying problems with PROSYM 37, they argue that its presentation during evidentiary hearings was too late in the proceeding for parties to adequately evaluate it, perform discovery, or prepare for cross examination. Accordingly, SDG&E and SCE argue that use of PROSYM 37 in this proceeding would violate due process, Public Utilities Code section 1822, and Rule 74.5(b) of the Commission's Rules of Practice and Procedure. They further argue that it is not appropriate to use PROSYM 37 for allocation of the revenue requirement because it does not correspond to the model used by DWR in deriving its revenue requirement, resulting in a potentially unfair mismatch.

While we generally agree with PG&E and ORA that we should be using the most accurate and up-to-date information and assumptions, SDG&E and SCE raise a valid concern. If we were to use PROSYM 37, it could result in a significant change in the allocation of the DWR revenue requirement as compared with PROSYM 36, presumably to the detriment of SDG&E and SCE. PROSYM runs are complex and highly technical, and PROSYM 37 was presented too late in this proceeding for parties to meaningfully evaluate or address its contents, methodology, or effects. Based on the facts before us, it would be inconsistent with due process to base our allocation upon PROSYM 37.[14] We are also concerned by the potential unfairness of basing our allocation of DWR's revenue requirement on one model, while the revenue requirement itself is based on another model.

Accordingly, for purposes of this decision, we are uniformly using PROSYM 36. Nevertheless, we do have a duty to ensure that our allocation is as consistent as possible with reality and with DWR's actual revenue requirement. The modifications and adjustments made in PROSYM 37 may also result in a somewhat lower revenue requirement than produced by PROSYM 36.[15] While the potential for a reduced revenue requirement is very attractive, PROSYM 37 by itself does not provide an adequate basis for a new revenue requirement. Among other things, DWR has its own processes and requirements for the preparation and presentation of a new revenue requirement. However, SDG&E and SCE (and any others) should be given a reasonable opportunity to provide suggestions to DWR, with everyone being subject to the same deadline. DWR can then evaluate those suggestions, and incorporate those it finds to be appropriate in its supplemental determination.

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[14] We do not reach the arguments based upon the Public Utilities Code and the Commission's Rules of Practice and Procedure. The due process ruling reached here is narrow, and based upon the specific facts of this case.

[15] DWR has not sought a reduced revenue requirement as a result of PROSYM 37.

DEMAND REDUCTION COSTS

DWR's revenue requirement includes $29 million in regards to a proposed demand response program intended to decrease customer demand during hours of high demand and short supply. These costs are included in DWR's forecast of ancillary service costs. We remove these costs from DWR's proposed revenue requirement. AB 1X, which authorized DWR to purchase energy and charge the costs of DWR purchased energy to utility customers did not give DWR the authority to incur costs for demand reduction programs, nor charge such costs to ratepayers. Since the $29 million in costs for demand reduction programs in DWR's current request is not within DWR's statutory authority to include in charges to consumers, we must remove those costs from the revenue requirement adopted today. We note that costs for demand reduction programs were not included in the prior DWR revenue requirement approved by the Commission in D. 02- 02052. The decision to remove these costs is not a reflection on the effectiveness or merit of such programs, which the Commission is not addressing in this proceeding.

Ratemaking and Remittance Issues

In D.02-03-062 we directed PG&E, SCE, and SDG&E to begin disbursement of proceeds to DWR, as required by their respective servicing agreements or Commission order, using the respective charges in cents-per-kilowatt-hour (kWh) of 9.211 for PG&E, 9.706 for SCE and 7.742 for SDG&E. These charges will change as a result of today's order, as described below. While the parties have made a number of proposed changes to current remittance practices, we adopt only those changes necessitated by policies we have adopted in related proceedings since D.02-02-052.

PG&E recommends that each utility remit variable costs under the contracts allocated to it to DWR on an actual incurred cost basis, in order to put D.02-09-053's variable-costs-follow-contracts requirement into effect. Second, each utility would remit ancillary services costs incurred on behalf of that utility, as well as DWR's share of surplus sales revenue, on an actual incurred cost basis. Finally, PG&E proposes that each utility remit the remaining fixed component of DWR's revenue requirement to DWR on a monthly basis. Under PG&E's approach, the amount to be remitted for the month would be remitted at the end of the following month in order to smooth the transition from the remittance methodology used for DWR's 2001-2002 revenue requirement to the remittance methodology used for the 2003 revenue requirement.

SCE proposes to continue its current process of remitting funds to DWR. SCE's practice is to transmit funds received from customers to DWR on a daily basis. SCE expresses concern that PG&E's proposal is not consistent with provisions of ABX1-1 because it results in commingling of payments by retail customers for DWR and URG power. SCE recommends that, in view of the uncertainties involved in PG&E's proposal, the Commission should allow SCE and DWR to determine their own appropriate remittance practices.

SDG&E recommends that the DWR remittance rate should be based on the forecast of DWR deliveries to bundled customers as a result of the pro rata allocation in D.02-09-053, and not on the deliveries utilized in the tables in DWR's August 16 Determination. According to SDG&E, the pro rata allocation will have the effect of increasing DWR deliveries to retail customers, so use of the forecast deliveries in DWR's August 16 Determination to set power charges would result in an overcollection by DWR.

ORA proposes that remittances to DWR consist of actual variable costs, plus the forecast residual revenue requirement, as adjusted for actual Direct Access Cost Responsibility Surcharge remittances. ORA asserts that its proposal is probably the easiest to implement since it results in a uniform "postage stamp" energy rate for all three utilities

TURN observes that PG&E has proposed some very significant changes to the current remittance procedures for transferring money to DWR, and that SCE has identified some potentially serious problems with PG&E's proposed approach. TURN urges the Commission not to change the remittance procedures unless DWR has explicitly agreed to any such changes.

In fact, DWR has not agreed to such changes. DWR agrees with SCE, and concurs in SCE's criticism of PG&E's proposal. We reject PG&E's proposal, namely that each utility remit to DWR, on a monthly basis, the fixed component of DWR's power cost revenue requirement after subtracting DWR's estimate of the variable costs of the contracts allocated to the utility. Absent agreement from DWR, and except as ordered here, utilities should maintain their current processes for remitting funds to DWR.

The changes to current remittance practices that we adopt today are limited to those necessitated by policies we have adopted in related proceedings subsequent to D.02-02-052.

First, we agree that each utility should remit DWR's share of surplus sales revenue directly to DWR on an actual incurred-cost basis.

Second, although we agree that ideally each utility should remit to DWR the variable costs of the contracts allocated to it on an actual incurred-cost basis, we are bound by the Rate Agreement to include these costs in the calculation of power charges that we adopt for each utility's customers.

Third, while we would prefer that each utility remit ancillary services costs incurred on behalf of that utility directly to DWR on an actual incurred-cost basis, we cannot do so, as previously described. We again are bound by the Rate Agreement to include these costs in the revenue requirement that is collected through the power charge.

Fourth, the revenue requirement that is collected from bundled ratepayers should be reduced by actual Direct Access Cost Responsibility Surcharge remittances, as ordered in D.02-11-022. However, since we do not have accurate information on the record about the volume of direct access sales that will be subject to the surcharge, we do not include any estimate of the impact of this adjustment in the charges we calculate today.

Finally, in order to calculate the new total power charges that will collect the total ratepayer revenue requirement, we use DWR retail sales that have been adjusted to reflect the protocol for off-system sales that we adopted in D.02-09-053. As a result of this adjustment, retail sales are significantly higher than the level assumed in DWR's August 16 Determination. Accordingly, DWR's cash flows will not require the increase of $517 million in its Operating Fund balance anticipated in the August 16 Determination. This adjustment should not affect the level of funds that DWR has available when needed.[16]

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[16] In its comments on the Proposed Decision, DWR should state whether this adjustment is appropriate.

To the extent necessary, the respective servicing agreements or Commission order for each utility should be modified to be consistent with the approaches described above.

Table C summarizes the remittance procedures described above, and illustrates how DWR will be paid for the entirety of its revenue requirement.

Table C
Calculation of Adopted IOU Power Charges

2003 DWR Expenses	
Power Costs	$4,119,902,243
Administrative and General Expenses	$28,400,000
Ancillary Services	$141,454,426
Increase in Operating Account Balance	$0
Total DWR Expenses	**$4,289,756,669**
Revenues Other Than Ratepayer Remittances	
Revenues from Sale of Excess DWR Power	$35,483,282
Interest Earnings	$59,007,505
Total Revenue Before Ratepayer Remittance	**$94,490,787**
DWR Revenue Required from Ratepayers	**$4,195224,265,882**

Cost Allocation Summary	**PG&E**	**SCE**	**SDG&E**	**Total**
DWR Revenue Required from Ratepayers				**$4,195,265,882**
Allocation of Total Revenue Requirement	**$1,837,485,458**	**$1,756,149,536**	**$601,630,887**	**$4,195,265,882**
less: Direct Access CRS Revenue	**$0**	**$0**	**$0**	**$0**
less: Revenue to maintain Operating Acct above $1 million	**$0**	**$0**	**$0**	**$0**
less: Allocation of Ancillary Services	**$61,775,961**	**$59,334,473**	**$20,343,992**	**$141,454,426**
Less: Allocation of Variable Costs	**$85,661,819**	**$65,501,750**	**$68,722,250**	**$219,885,819**
Equals: Residual Fixed Costs	**$1,690,047,678**	**$1,631,313,313**	**$512,564,645**	**$3,833,925,636**
2003 DWR Delivered Energy	$19,205,963,516	18,459,409,403	6,398,534,999	44,063,907,918
Components of IOU Power Charge ($/kWh)				
Ancillary Services Cost Component	$0.00363	$0.00320	$0.00314	$0.00321
Variable Power Cost Component	$0.00446	$0.00355	$0.01074	$0.00499
Fixed Power Cost Component	$0.08800	$0.08837	$0.08011	$0.08701
Charge Component to Fund Operating Account	$0.00000	$0.00000	$0.00000	$0.00000
Total IOU Power Charge ($kWh)	**$0.09569**	**$0.09513**	**$0.09401**	**$0.09521**

Total Ratepayer Revenues	**$1,837,485,458**	**$1,756,149,536**	**$6051630,887**	**$4,195,265,882**

2001-2002 TRUE UP

In response to recommendations from SDG&E and TURN, and with the agreement of DWR, ALJ Allen ruled that the issues relating to the true-up of DWR's 2001-2002 revenue requirement would be deferred until actual data for 2002 was available. (Transcript v.48, pp.6802-04.) This ruling is appropriate, and is consistent with D.02-02-052, with D.02-02-051, and with the Rate Agreement between the Commission and DWR.

In a separate letter/memorandum dated October 16, 2002, DWR states that actual data for the entire 2001-2002 period will be available in April, 2003. Parties were given the opportunity to recommend a process and schedule for the true-up phase in their briefs, to eliminate the burden of filing a separate pleading.

SDG&E states that it cannot at this time identify what specific issues may be presented, but provides a proposed schedule for the true-up process, with parties filing proposals and procedural recommendations within 21 days after DWR releases its recorded data for the 2001-2002 revenue requirement period, followed by workshops or hearings, as needed. SDG&E expresses hope that the true-up process will be relatively noncontroversial.

SCE argues that the scope of the true-up proceeding should consist of a true-up of DWR's total 2001-2002 forecast expenses to actual expenses, true-up of the allocation of those actual expenses to the utilities' customers, and a true-up of the previous allocation of "net borrowed proceeds" and what the utilities' customers actually pay to DWR. SCE believes its customers have overpaid DWR's prior revenue requirement, and accordingly recommends an extremely expedited schedule for the true-up phase, beginning (and ending) prior to the availability of actual 2002 data.

PG&E, on the other hand, argues that no re-allocation true-up of DWR's 2001-2002 revenue requirement is necessary or appropriate, and requests a Commission determination that no true-up will be made.[17] PG&E appears to be most concerned about the possibility of an inter-utility true-up of the sort desired by SCE. In the alternative, PG&E requests that any true-up be completed before the end of 2002.

The schedules proposed by SCE and PG&E are not realistic, would put undue burdens on both parties and the Commission, would require another subsequent true-up, are not an efficient use of resources, and constitute a collateral attack on ALJ Allen's ruling.

We will not determine here the specific details of how any true-up of DWR's 2001-2002 revenue requirement is to be done, other than to note that DWR will not be required to return funds already received from ratepayers. All participants will be given an opportunity to express their positions in a separate true-up phase, consistent with ALJ Allen's ruling.[18] While SDG&E's proposed schedule is reasonable, we do not adopt it here, but leave to the ALJ and Assigned Commissioner the task of establishing a schedule and process for a

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[17] However, PG&E's October 8, 2002 filing re surplus sales allocation states: "Differences between the forecast used to set the revenue requirement and the actual surplus sales revenue will be trued up in a future DWR Revenue Requirement Proceeding." (*Id.*, p.3.)

[18] At that time PG&E may, if it wishes, renew its argument that no true-up should be done.

true-up phase that incorporates actual data for DWR's 2001-2002 revenue requirement period.

Other Issues

PG&E recommends that the Commission retain the one-half cent per kWh "Catch-Up" surcharge originally adopted in D. 01-05-064 to partially offset DWR's requested increase in its revenue requirement. SCE similarly recommends that the Commission defer a potential rate increase by authorizing SCE to use the Catch-Up surcharge revenues to offset the increase in DWR's revenue requirement. (*See*, Resolution E-3776, issued June 6, 2002.) We will not modify our prior decisions regarding the Catch-Up surcharge here.

PG&E recommends that the Commission make clear to DWR that the Commission expects DWR to act immediately to lower its revenue requirement should DWR's costs become significantly lower. (PG&E Opening Brief, pp.31-32.) TURN agrees with PG&E. (TURN Reply Brief, p.8.) While we would hope this would go without saying, it bears repeating: every dollar of DWR's revenue requirement is a dollar that must be paid by California ratepayers, so every dollar by which that revenue requirement can be reduced is another dollar that can remain in the pocket of a California ratepayer. We encourage DWR to do all it can to reduce its costs, and to promptly lower its revenue requirement accordingly. We believe that DWR's supplemental determination may reflect a reduced revenue requirement, and we expect that DWR will make every effort to further minimize its revenue requirement.

We note that an update may have a significant downward impact on DWR's revenue requirement, and the resulting rates charged to customers in California. At issue are over $170 million in potentially duplicative ancillary service costs being; over a billion of cash reserves that should be unnecessary as the utilities resume the responsibility for procuring energy to meet their net short positions in 2003, and other matters. By appropriately updating their revenue requirement in a timely manner, DWR can help us ensure that the burden on ratepayers and the economy of California to pay for expensive DWR power is minimized.

SDG&E argues that no part of any DWR revenue requirement pertaining to power contracts entered into by DWR between August 22, 2002 and January 1, 2003 (pursuant to D.02-08-071) be allocated to SDG&E. According to SDG&E, any such contracts would be for the sole benefit of the customers of SCE and PG&E, and SDG&E customers should not have to bear their costs. SDG&E acknowledges that DWR's revenue requirement does not currently contain any such costs, but SDG&E expects that DWR may incur costs as provided for in D.02-08-071, and it would be appropriate for ratemaking mechanisms to be put in place in anticipation.

In D.02-08-071, we authorized PG&E and SCE to enter into power contracts using the credit backing of DWR. We did not extend that authority to SDG&E, as we found that there was no need for DWR to "backstop" purchases by SDG&E. Since the contracts potentially at issue would be entered into by the individual utilities on behalf of their own customers (as opposed to the earlier contracts negotiated by DWR on behalf of the whole state) it is reasonable to assign the costs of those contracts to the utility that entered into them. Consistent with SDG&E's request, to the extent that DWR's revenue requirement includes costs associated with this category of contracts, those costs will be directly assigned to the utility that entered into any such contract or contracts.

Implementation

To reduce the potential for confusion and uncertainty, we will describe the implementation process for the adopted revenue requirement allocation and for DWR's supplemental determination.[19]

A. Narrative Explanation of the Revenue Requirement Allocation

Definitions

1. Variable Costs: Variable costs, as defined in D.02-09-053, are those that can be avoided by dispatch decision. Specifically, variable costs are the energy payments associated with the dispatchable contracts assigned to the IOUs by D.02-09-053.
2. Residual Fixed Costs: Residual fixed cost is calculated by subtracting variable costs from the adjusted DWR revenue requirement. Residual fixed costs would include fixed contract costs, ancillary services, administrative and general expenses, and operating balances.

Revenue Requirement Adjustments

1. The revenues required from ratepayers in 2003 by DWR ($4.224 Million) is the sum of Fixed and Variable Contract costs, A&G Expenses, Ancillary Services, and Operating Reserves, minus Off-System Sales Revenue and Interest Earnings.

Allocation of 2003 DWR Revenue Requirement

1. Calculate each IOU's portion of DWR supplied energy.
    a. Determine amount of DWR supplied energy in each IOU resource portfolio.

[19] Appendix A provides additional detail regarding the allocation methodology.

   b. Adjust the amount of DWR supplied energy for each IOU by adding DWR share of Pre-DA migration to DWR supplied energy.

   c. Subtract DWR's portion of surplus energy from DWR's Pre-DA supplied energy.

2. Allocate adjusted DWR Rev Req. ($4.224 million) to each IOU according to their share of DWR supplied energy.

   a. Calculate each IOU's DWR supplied energy allocation factor by dividing each IOU's portion of DWR supplied energy by the total of DWR supplied energy.

   b. Determine each IOU's share of the DWR Rev Req. by multiplying the adjusted DWR RR by each IOU's DWR supplied energy allocation factor.

   c. Calculate each IOU's residual fixed costs by subtracting variable costs, assigned by D.02-09-053, from each IOU's share of DWR Rev Req.

B. The DWR Supplemental Determination Process

There are four areas where a supplemental determination from DWR is necessary for us to optimally perform our allocation of DWR's 2003 revenue requirement. As described above, those areas are treatment of direct access migration, forecasted costs of ancillary services, opportunity for contribution to the modeling process, and treatment of revenues from sales of excess energy.

The direct access and sales revenue issues have been addressed in other Commission decisions, as described above, and we need to ensure that our allocation of DWR's revenue requirement here reflects the effects of those decisions, but we cannot do so without DWR's assistance. These are basically technical adjustments or updates that DWR is already aware of, and should be able to make without significant difficulty. If DWR (or anyone else) has questions or concerns on how these issues should be treated, they should contact the staff of the Commission's Energy Division for guidance.

Ancillary services appears to be an area where DWR can significantly reduce its revenue requirement by using more current assumptions, and by obtaining further input from the utilities.

The issues relating to the use of PROSYM 36 versus PROSYM 37 are procedural in nature. In order to ensure that similar difficulties are not presented by DWR's supplemental determination, we will set out a process for implementing that determination.

All utilities and other parties who wish to make suggestions to DWR relating to the input, assumptions and processes to be used in the modeling and preparation of its supplemental determination shall provide those suggestions no later than December 30, 2002. DWR can then incorporate those suggestions it deems appropriate, along with the direct access and sales revenues adjustments, and any other updates or corrections made by DWR. After it performs the ensuing model run and post-processing, DWR will submit its supplemental determination to the Commission.

The Commission will then use the supplemental determination to re-allocate DWR's 2003 revenue requirement on a highly expedited basis. In order to avoid unnecessary delay in implementing the revised allocation, the Commission will use the methodology approved today, with the exception of the allocation of ancillary services. Re-litigation of the allocation methodology will not be allowed (again with the exception of ancillary services), absent extraordinary circumstances. The Commission intends to hold a technical workshop, conducted by the Commission's Energy Division shortly after DWR submits its supplemental determination, to ensure that all parties have a common understanding of the supplemental determination. After the workshop will come an expedited paper-only proceeding, followed by a decision implementing a revised allocation for 2003.

Since the revised allocation should be fairer, and should also reflect a reduced revenue requirement, the sooner it can be implemented, the better. We accordingly urge DWR to prepare and submit its supplemental determination as quickly as possible, consistent with all legal and procedural requirements.

Rehearing and Judicial Review

This decision construes, applies, implements, and interprets the provisions of Assembly Bill (AB)1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Pub. Util. Code § 1731 (c) (applications for rehearing are due within 10 days after the date issuance of the order or decision) and Pub. Util. Code § 1768 (procedures applicable to judicial review) are applicable.

Comments on Proposed Decision

The alternate decision of President Lynch was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were received __________________________.

Assignment of Proceedings

Loretta M. Lynch and Geoffrey F. Brown are the Assigned Commissioners and Peter Allen is the assigned Administrative Law Judge in these proceedings.

Findings of Fact

1. Among the allocation methodologies proposed in this proceeding, ORA's proposed allocation methodology is both consistent with recent Commission decisions and provides the fairest allocation of DWR's 2003 revenue requirement.
2. ORA's proposed allocation methodology should be modified to reflect differences in line loss among the utilities to avoid cross-subsidies.

3. Using revenues from off-system sales to directly offset the revenue requirement of the dispatching utility provides a better incentive for economic dispatch than would pooling of revenues from off-system sales.

4. Allocation of DWR's revenue requirement should take into consideration direct access customers subject to the Cost Responsibility Surcharge (CRS) set in R.02-01-011.

5. Consideration of direct access customers subject to the Cost Responsibility Surcharge (CRS) set in R.02-01-011 requires the results of a "Direct Access-In" modeling run from DWR's consultant.

6. A "Direct Access-In" modeling run was not available in time to become part of the evidentiary record in this proceeding.

7. D.02-09-053 required that revenues from sales of excess energy should be allocated pro rata between DWR and the utilities.

8. DWR's August 16 Determination does not reflect the treatment of revenues from sales of surplus energy adopted in D.02-09-053.

9. Crediting of revenues from the sale of excess energy to the customers of the utility involved in the transaction provides the proper incentives for utilities to maximize the revenues from sales of surplus energy.

10. Utilities are not required to obtain ancillary services through DWR.

11. Utilities differ in their potential need for DWR to provide ancillary services in 2003.

12. DWR's August 16 determination does not reflect differences between utilities relating to DWR provision of ancillary services.

13. DWR's August 16 Determination was based upon a modeling run known as PROSYM 36.

14. PROSYM 36 does not reflect the treatment of excess energy sales revenue adopted in D.02-09-053.

15. PROSYM 36 does not contain the most recent data and assumptions.

16. The output of the modeling run known as PROSYM 37 was presented too late in the proceeding to allow all parties a reasonable opportunity to evaluate and address its contents and impacts.

17. A supplemental determination from DWR that provides the necessary additional information would allow the Commission to improve the accuracy and equity of its allocation of DWR's 2003 revenue requirement.

18. Significant changes in the procedures for making remittance payments to DWR are not necessary.

19. PG&E's proposal to alter the procedures for remittance payments to DWR is a significant change to current practices and is opposed by DWR.

20. The evidentiary record does not contain accurate information about the volume of direct access sales that will be subject to the surcharge ordered in D.02-11-022.

21. Actual data for DWR's revenue requirement for the year 2002 will not be available until 2003.

22. With DWR's agreement, ALJ Allen deferred all issues relating to the true-up of DWR's 2001-2002 revenue requirement until 2003.

23. D.02-08-071 authorized PG&E and SCE to enter into power contracts using the credit backing of DWR, but did not authorize SDG&E to do so.

24. DWR includes $29 million in its proposed revenue requirement for demand reduction efforts.

25. Assembly Bill 1X does not give DWR the authority to incur costs for demand reduction programs or to charge such costs to utility customers.

Conclusions of Law

1. ORA's proposed methodology, with the modifications described above, should be adopted.

2. A "Direct Access-In" modeling run should be utilized for allocation when it becomes available, consistent with due process.

3. Until a "Direct Access-In" modeling run becomes available, a modeling run without "Direct Access-In" should be utilized.

4. Revenues from sales of excess energy should offset the portion of the DWR revenue requirement allocated to the customers of the dispatching utility.

5. DWR's August 16 Determination, October 23 Memorandum, and the Rate Agreement preclude the Commission from allocating to a utility the actual costs that DWR incurs for providing ancillary services to that utility.

6. The use of PROSYM 37 at this time would not be consistent with due process.

7. The use of PROSYM 36 at this time does not present due process issues.

8. A supplemental determination from DWR, as described above, could remedy the due process problems of using an updated modeling run.

9. All parties should have equal opportunity to provide input to DWR's supplemental determination, and should be subject to the same deadline.

10. Utilities should generally maintain their current processes for remitting funds to DWR.

11. Changes to current remittance practices should be limited to those necessitated by Commission decisions subsequent to D.02-02-052.

12. Each utility should remit DWR's share of surplus sales revenue directly to DWR on an actual incurred-cost basis.

13. The Rate Agreement bars the utilities from remitting variable costs and ancillary services costs directly to DWR on an actual incurred-cost basis.

14. Calculation of the power charge should use DWR retail sales adjusted to reflect the protocol for off-system sales adopted in D.02-09-053.

15. It is reasonable to defer until 2003 all issues relating to the true-up of DWR's 2001-2002 revenue requirement.

16. Any 2003 DWR revenue requirement pertaining to power contracts entered into by DWR between August 22, 2002 and January 1, 2003 (pursuant to D.02-08-071) should be allocated to the utility entering the particular contract.

17. This decision construes, applies, implements, and interprets the provision of AB 1X (Chapter 4 of the Statues of 2001-02 First Extraordinary Session). Therefore, Pub. Util. Code § 1731 (c) (applications for rehearing are due within 10 days after the date of issuance of the order or decision) and Pub. Util. Code § 1768 (procedures applicable to judicial review) are applicable.

18. Costs for demand reduction programs cannot be included in DWR's revenue requirement and charged therein to ratepayers.

O R D E R

IT IS ORDERED that:

1. Department of Water Resources' (DWR's) 2003 revenue requirement is to be allocated according to the allocation methodology proposed by Office of Ratepayer Advocates (ORA), as modified and described above, and as set forth in Appendix A.

2. Based on the adopted allocation methodology, DWR's total 2003 revenue requirement is allocated to the utilities as follows:

PG&E: $1,837,485,458

SCE:	$1,756,149,536
SDG&E:	$ 601,630,887

3. Revenues from excess sales are to be accounted for as described above.

4. DWR's forecast ancillary services costs are to be allocated on the same basis as fixed costs until an improved allocation method is approved by the Commission.

5. No later than December 30, 2002, parties may submit information and assumptions for DWR's use in a supplemental determination. If parties do so, they shall also file such information and assumptions at the Commission's Docket Office and serve them on all parties to this proceeding.

6. DWR is encouraged to promptly submit a supplemental determination, as described above.

7. Each utility shall remit DWR's share of surplus sales revenue directly to DWR on an actual incurred-cost basis.

8. Calculation of the power charge shall use DWR retail sales adjusted to reflect the protocol for off-system sales adopted in D.02-09-053, as described above.

9. The respective servicing agreement or Commission order for each utility should be modified to the extent necessary to be consistent with the approaches described above.

10. Any true-up of DWR's 2001-2002 revenue requirement is deferred until actual data for 2002 is available, consistent with the ruling of Administrative Law Judge (ALJ) Allen.

11. Any 2003 DWR revenue requirement pertaining to power contracts entered into by DWR between August 22, 2002 and January 1, 2003 (pursuant to D.02-08-071) shall be allocated to the utility entering the relevant contract.

12. The Commission or Assigned Commissioner or Administrative Law Judge shall issue further orders or rulings as needed regarding the process and schedule of future phases of this proceeding.

13. The Commission or ALJ shall issue further orders or rulings as needed regarding the process and schedule of future phases of this proceeding.

14. $29 million for demand reduction programs is removed from DWR's proposed revenue requirement.

This order is effective today.

Dated, ___________________, at San Francisco, California

APPENDIX A

Appendix A

Allocation Methodology for 2003 DWR Rev. Req.

Note: Values may not sum to total due to rounding

1. Calculate adjusted DWR revenue requirement.

Line	($000)	Total	Source:
1	Power Costs	$4,119,902	August 16th Determination
2	Admin and General Expenses	$28,400	August 16th Determination
3	Ancillary Services	$170,454	August 16th Determination
4	Net Operating Revenues	$0	August 16th Determination
5	DWR Power Sales Revenues	$(35,483)	Line 21
6	Interest Earnings on Fund Balances	$(59,007)	August 16th Determination
7	ORA Adjusted Revenue Requirement	$4,224,266	Sum of Line 1 to Line 6

1. Calculate each IOU's portion of DWR Pre-DA supplied energy.
   a) Calculate the proportion of the DWR and URG supplied energy in each IOU's resource portfolio.

Line	GWh	PG&E	SCE	SDG&E	Source
8	Supply from URG*	52,756	57,881	7,056	ProSym 36
9	Supply from DWR	21,835	22,246	6,953	ProSym 36
10	Total Supplied Energy	74,591	80,127	14,009	Line 8 + Line 9
11	URG % of IOU Portfolio	71%	72%	50%	Line 8 / Line 10
12	DWR % of IOU Portfolio	29%	28%	50%	Line 9 / Line 10

*For URG supplied energy, ORA referenced line Total Generation from "DWR Run37 CA IOU Production Costs with Contracts Reallocated.xls." Since this reference does not include bilateral contracts, Energy Division recalculated URG supplied energy by adding together Retained Generation, Bilaterals, and QFs from "DWR Run36 CA IOU Production Costs interim with CALP DWRN4-5 A.xls."

b) Adjust the amount of DWR supplied energy for each IOU by adding DWR's share of Pre-DA migration to DWR supplied energy.

Line	GWh	PG&E	SCE	SDG&E	Source
13	Direct Access	0	0	0	Need Supplemental DWR Modeling
14	Departing Load	0	0	0	Need Supplemental DWR Modeling
	Total Pre-DA Supplied Energy				
15	DWR Share of Portfolio	21,835	22,246	6,953	Line 9 + Line 13 + Line 14

c) Subtract DWR's portion of surplus energy from DWR's share of Pre-DA supplied energy to determine DWR's adjusted supplied energy.

Line	GWh	PG&E	SCE	SDG&E	Source
16	URG% of IOU Portfolio	2,709	7,052	133	ProSym 36
17	DWR % of IOU Portfolio	1,9794	5,159	64	Line 16 * Line 11
18	DWR Share of Surplus Energy	731	1893	69	Line 16 * Line 12
19	Adjusted DWR Supplied Energy	21,104	20,353	6,884	Line 15 – Line 18

*In its Allocation Comparison Exhibit, ORA used surplus sales numbers that were cash based, not accrued. To accurately model the impact of D.02-03-059 on surplus energy sales and revenues, the Energy Division used monthly surplus energy sales and revenues in DWR's model (RRG3BV10.XLS). and Prosym 36 output data provided to parties.

d) Calculate URG and DWR share of revenue from surplus sales.

Line	($000)	PG&E	SCE	SDG&E	Source
20	Revenue from Surplus Sales ($000)*	$15,609	$43,638	$1,510	ProSym 36
21	Utility Share of Surplus Revenue ($000)	$6,467	$18,302	$506	Line 20 * Line 11
22	DWR Share of Surplus Revenue ($000)	$9,143	$25,336	$1,004	Line 20 * Line 12

*In its Allocation Comparison Exhibit, ORA used surplus sales numbers that were cash based, not accrued. To accurately model the impact of D.02-03-059 on surplus energy sales and revenue, the Energy Division used monthly surplus energy sales and revenues in DWR's model (RRG3BV10.XLS). and ProSym 36 output data provided to parties.

2) <u>Allocate adjusted DWR Rev Req. ($4.564 million) to each IOU according to their share of DWR pre-DA supplied energy.</u>

a) Calculate each IOU's supplied energy allocation factor by dividing each IOU's portion of DWR supplied energy by the total of DWR supplied energy

Line	(GWh)	PG&E	SCE	SDG&E	Total	Source:
23	DWR Supplied Energy	21,104	20,353	6,884	47,968	Line 19
24	% DWR Supplied Energy	43.66%	42.10%	14.24%	100%	Line 23 / Total Line 23

a.) Determine each IOU's share of the DWR Revenue Requirement by multiplying the adjusted DWR RR by each IOU's supplied energy allocation factor.

Line	($000)	PG&E	SCE	SDG&E	Total	Source:
25	DWR Power Charge Expense	$4,318,757				Line1 + Line 2 + Line 3 + Line 4
26	% Pre-load Migration Supplied Energy	43.66%	42.10%	14.24%	100%	Line 24
27	IOU Share of Adjusted DWR Rev Req.	$1,885,389	$1,818,330	$615,038	$4,318,757	Line 25 * Line 26

b) Calculate each IOU's residual fixed costs by subtracting variable contract costs from each IOU's share of DWR Rev Req.

Note: Due to rounding, sum might not equal total.

Line	($000)	PG&E	SCE	SDG&E	Total	Source:
28	IOU Share of Adjusted DWR Rev Req.	$1,885,389	$1,818,330	$615,038	$4,318,757	Line 27
29	Ancillary Services	$74,413	$71,767	$24,275	$170,454	August 16th Determination Line 24
30	Forecast Variable Costs	$85,662	$65,502	$68,722	$219,886	ProSym 36
31	Residual (Fixed Cost)	$1,725,313	$1,681,061	$522,042	$3,928,416	Line 28-Line 29-Line 30
	LESS:					
32	Interest Earned	($25,756)	($24,571)	($8,680)	($59,008)	August 16th Determination *Line 24
33	DWR Surplus Energy Revenue	($9,143)	($25,336)	($1,004)	($35,483)	Line 22
34	DWR Revenue Required From Ratepayers	$1,850,485	$1,768,150	$605,631	$4,224,266	Sum of Lines 29 through 33